

Technical Remarks Document for the Proposed Permit

TECHNICAL REVIEW AND EVALUATION OF APPLICATION FOR AIR QUALITY PERMIT NO. 1000109

I. INTRODUCTION

This Class I (Title V or Part 70) Permit is for the operation of the Apache Generating Station (Apache), located approximately 3 miles south of the town of Cochise, Cochise County, Arizona. Apache is owned and operated by Arizona Electric Power Cooperative, Inc. (AEPCO). The plant currently supplies electric power to six rural electric distribution systems serving portions of Arizona, California, and New Mexico. It also sells wholesale power to individual municipal, commercial and industrial customers in Arizona.

A. Company Information

Facility Name: Apache Generating Station

Mailing Address: P.O. Box 670, Benson , AZ 85602

Facility Address: Route 1, Box 704, Cochise, Cochise County, Arizona 85606

B. Attainment Classification

The source is in an attainment area for TSP, SO₂, CO, Ozone, PM-10 and NO₂.

II. PROCESS DESCRIPTION

The maximum process rates based on base load operating conditions on an annual basis and operating hours of the generating units at Apache are summarized in Table 1. Please refer to the application for the maximum process rates based on peak load operating conditions on an hourly basis.

Table 1: Maximum Process Rates

Emission ID/Unit	Hours/yr	MW	MW-hr/yr
001-Gas Turbine 1	8760	10.4	91104
002-Gas Turbine 2	8760	19.8	173448
003-Gas Turbine 3	8760	64.9	568524
004-Steam Unit 1	8760	75	657000
005-Steam Unit 2	8760	195	1708200
006-Steam Unit 3	8760	195	1708200

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Emission ID/Unit	Hours/yr	MW	MW-hr/yr
Total			4906476

Note: The information in this table was provided by AEPCO in their application for a Class I Permit. The process rates and operating hours listed are for informational purposes only. In addition, this information should not be construed as establishing enforceable limitations of any form on Apache operations.

The coal handling system at AEPCO, which includes crusher, sizing screens, silos, and loading and unloading systems, can transfer approximately 2,102,400 tons of coal to Steam Units 2 and 3 each year. This throughput is based on the maximum capacity of the reclaim operations, which is 240 tons per hour to the boiler. The maximum annual process rate for the limestone handling operations at AEPCO, which produce limestone slurry for Apache's Sulfur Dioxide Absorption System (SDAS), is approximately 43,800 tons per year.

Data from the emission sources forms included in AEPCO's Class I Permit application shows that AEPCO has the potential to emit more than 100 tons per year (tpy) of all primary criteria pollutants (except lead) and more than 10 tpy of formaldehyde and nickel. This means that Apache is classified as a "major stationary source" pursuant to Clean Air Act Section 302.

Apache Steam Units 2 and 3 burn coal primarily. Apache Steam Unit 1 and Gas Turbines 1 through 3 burn natural gas primarily. AEPCO has proposed several alternate operating scenarios for Apache Generating Station. These are summarized in Table 2, and involve the burning of other types of fuel in each generating unit. Steam Units 2 and 3 use natural gas ignitors during start-up and certain other operating conditions. These conditions include boiler flame stabilization, equipment testing, and load stabilization. On occasion AEPCO will use the ignitors to provide an additional source of fuel to the boiler (up to 20% heat input), which is an alternate operating scenario for Steam Units 2 and 3 (i.e., co-firing natural gas and coal). AEPCO has requested the ability to combust on-spec used fuel oil and on-spec waste oil in Steam Units 1, 2, and 3. If used fuel oil and used oil are burned, it would be in combination with a primary fuel in Steam Units 1, 2, or 3.

Steam Unit 1 and Gas Turbine 1 have the ability to be operated in combined cycle operation or simple cycle operation. Under combined cycle operation, exhaust from Gas Turbine 1 is used to provide intake air to the Steam Unit 1 windbox. This is done to increase the load output and efficiency of the system. In simple cycle operation, AEPCO provides combustion air to the boiler through the use of the unit's two forced draft fans.

Steam Units 2 and 3 at AEPCO have the capability of burning coal. When coal is burned, it must be pulverized into a fine powder before it is combusted in the boilers. This processing starts when coal is transferred from the coal handling system to the boiler crusher/dryers. The crusher/dryers reduce coal size and remove excess surface moisture. The smaller coal pieces are then sent to the ball tube mills where they are pulverized. Pulverized coal passes through the classifiers. Coal that is still too large is sent back to the ball tube mills for additional pulverizing, while adequately sized coal

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goes to the boiler for combustion.

In addition to producing radiant heat necessary to create steam to drive the Steam Unit 2 and 3 turbines and generators, the combustion taking place in the boiler also creates hot exhaust gas. The exhaust gas from the boiler is first sent to the electrostatic precipitator (ESP) for removal of fly ash and unburned carbon from the gas stream. Bottom ash falling to the bottom of the furnace is removed with the help of hydroejectors. Gas leaving the ESP enters the SDAS where the sulfur dioxide is removed from the gas stream. The SDAS on each unit consists of two wet limestone scrubber modules. The system is designed for operation of only one module at a time; the second module is maintained as a standby unit. The scrubbed gas is then discharged to the atmosphere via a common stack for the two units.

Table 2: Operating Scenarios

Source	Primary Operating Scenarios	Alternate Operating Scenarios
Gas Turbines 1 and 2	Natural Gas	
		#2 fuel oil
Gas Turbine 3	Natural Gas	
Steam Unit 1		#2 through #6 grades fuel oil
	Natural Gas	
		#2 through #6 grades fuel oil
		Co-firing #2 through #6 grades fuel oil and used oil or used fuel oil
		Co-firing of natural gas and used oil or used oil fuel.
		Co-firing #2 through #6 grades fuel oil and natural gas
Steam Units 2 and 3	Coal	
		Natural gas
		Co-firing coal and natural gas
		Co-firing natural gas and used oil or used fuel oil.
		Co-firing coal and used oil or used fuel oil

Note: Used oil is to be combusted in either Steam Unit 1, 2, or 3 only; used oil is not to be combusted for more than 40 hours/year; and used oil when mixed with virgin fuel oil is not to exceed 5% of the total volume of fuel in any fuel storage tank.

III. EMISSIONS

The Apache plant has the capability of operating under different scenarios as outlined in Section II of this Technical Remarks document. Typical operating parameters of the turbines and the steam units are given in Table 3. Table 4 summarizes the potential to emit (PTE), allowable emissions, test

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results, and the emissions inventory (EI) for these units. The emission factors used to calculate the potential to emit are from AP-42 (1/95 ed.). AEPCO, in its application, provided the emission factors for the gas turbines and the steam generators from EPA publication EPA 450/4-90-003. These numbers do not vary significantly from AP-42 numbers. The characteristics of fuel oil #6 were used to conservatively estimate the emissions from used oil burning due to the lack of availability of emissions calculation factors for used oil burning. Although calculations have been shown here only for the worst-case scenario of burning fuel oil no. 6 in steam unit 1 and turbine #3, the steam unit and the turbine have the capability to burn fuel oil nos. 2 through 6. The allowable emissions are calculated using the standards under 40 CFR 60, Subpart D, A.A.C. R18-2-703, and A.A.C. R18-2-719. The reader is advised to peruse the permit application for HAPs emissions calculations. For other emissions calculations, the reader is referred to the attachment to this technical support document.

Table 3 Typical Operating Parameters

Description	Steam Unit 1	Steam Units 2 and 3	Gas Turbine 1	Gas Turbine 2	Gas Turbine 3
Rated generating capacity (MW)	Gas: 75 Oil: 75 Coal: na	Gas: 195 Oil: na Coal: 195	Gas: 10.4 Oil: 10.4	Gas: 19.8 Oil: 19.4	Gas: 64.9 Oil: 63.4
Maximum generating capacity (MW)	Gas: 85 Oil: 85 Coal: na	Gas: 210 Oil: na Coal: 210	Gas: 13.2 Oil: 13.2	Gas: 26.1 Oil: 25.6	Gas: 72.3 Oil: 70.7
Net heat rate at Rated capacity (Btu/KWh)	Gas: 11350 Oil: 12900 Coal: na	Gas: 10000 Oil: na Coal: 9800	Gas: 19100 Oil: 19400	Gas: 19100 Oil: 14200	Gas: 13500 Oil: 13500
Net heat rate at maximum capacity (Btu/KWh)	Gas: 11200 Oil: 14150 Coal: na	Gas: 9950 Oil: na Coal: 9700	Gas: 16700 Oil: 16600	Gas: 14300 Oil: 13200	Gas: 12100 Oil: 12100
Heating value of natural gas (Btu/scf)	1032	1032	1032	1032	1032

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Description	Steam Unit 1	Steam Units 2 and 3	Gas Turbine 1	Gas Turbine 2	Gas Turbine 3
Heating value of fuel oil (Btu/gal)	135000 (#2) 150000 (#6)	na	135000 (#2)	135000 (#2)	135000 (#2) 150000 (#6)
Heating value of coal (Btu/lb)	na	12000	na	na	na
Sulfur content of fuel oil	0.05% (#2) 0.75% (#6)	na	0.05% (#2)	0.05% (#2)	0.05% (#2) 0.75% (#6)
Sulfur content of coal	na	0.26 - 1.0%	na	na	na

Note: The parameters listed in this table are based on the PTE calculations AEPCO provided to support their application for a Class I Permit. In addition, this information should not be construed as establishing enforceable limitations of any form on Apache operations.

While AP-42 emissions factors from 1/95 are more recent and more accurate than the emission factors used by AEPCO, the resulting increases (and decreases in some cases) in calculated emissions do not change the source category status, and do not trigger any new applicable requirements. Therefore, the use of emission factors from EPA 450/4-90-003 to calculate emissions is acceptable.

AEPCO in its Title V permit application provided the performance guarantees given by the manufacturers of the air pollution control device. For the sulfur dioxide absorption systems, the manufacturer specified a minimum of 85% SO₂ removal efficiency for any load on the steam generator from 110% down to 20% of design rating and burning coal. For the electrostatic precipitators, the manufacturer specified a minimum of 99.56% by weight collection efficiency.

The formula used to calculate uncontrolled potential emissions from units burning natural gas is as follows:

$$\text{Emissions (tpy)} = \text{Emission Factor (lb/MMcft)} \times \text{Net Heat Rate (Btu/KWh)} \times \text{Max. Generating Capacity (KW)} / \text{Heating Value of Fuel (Btu/cft)} / 10^6 \text{ (cft/MMcft)} \times 8760 \text{ (hr/yr)} / 2000 \text{ (lbs/ton)}$$

The formula used to calculate uncontrolled potential emissions from units burning fuel oil is as follows:

$$\text{Emissions (tpy)} = \text{Emission Factor (lb/1000 gal)} \times \text{Net Heat Rate (Btu/KWh)} \times \text{Max.}$$

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$$\text{Generating Capacity (KW)/Heating Value of Fuel (Btu/gal)} \times 8760 \text{ (hr/yr)/2000 (lbs/ton)}$$

The formula used to calculate the uncontrolled potential emissions from units burning coal is as follows:

$$\text{Emissions (tpy)} = \text{Emission Factor (lb/ton)} \times \text{Net Heat Rate (Btu/KWh)} \times \text{Max. Generating Capacity (KW)/Heating Value of Fuel (Btu/lb)/2000 (lb/ton)} \times 8760 \text{ (hr/yr)/2000 (lbs/ton)}$$

Potential emissions from the Apache plant are presented in the following table. They may be used for the following purposes:

- (i) Ascertaining “major source” status of the Apache plant pursuant to CAA Sec 501 (2);
- (ii) Comparing source potential-to-emit with emission rates allowable by relevant standards; and
- (iii) Comparing source potential-to-emit with emissions inventory and test data.

This comparison serves as a summary of existing information on emissions from the Apache plant. These emissions calculations are **not** meant to establish any baseline emissions levels. These emissions figures (except for the ALLOWABLE emissions) are **not** meant to be emissions limitations of any form.

Table 4: Comparison among PTE, Allowable Emissions, Test Data, and EI

Unit	Pollutant	PTE (tpy)	Allowable ⁽¹⁾ (tpy)	Test Data ⁽³⁾ (tpy)	EI 1995 (tpy)
Steam Unit 1 (Natural gas)	PM	10.84	800	n/a	0.49
	SOx	2.17	n/a	n/a	0.80
	NOx	1987.07	n/a	n/a	61.45
	VOCs	5.06	n/a	n/a	0.69
	CO	144.51	n/a	n/a	19.66
Steam Unit 2 (Natural Gas)	PM	24.83	854	n/a	0.01
	SOx	4.97	n/a	n/a	n/a
	NOx	1537 ⁽²⁾	1710	n/a	n/a
	VOCs	11.59	n/a	n/a	0.41
	CO	331.05	n/a	n/a	11.79

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Unit	Pollutant	PTE (tpy)	Allowable ⁽¹⁾ (tpy)	Test Data ⁽³⁾ (tpy)	EI 1995 (tpy)
Steam Unit 3 (Natural Gas)	PM	24.83	854	179	0
	SO _x	4.97	n/a	n/a	n/a
	NO _x	1537 ⁽²⁾	1710	1537	n/a
	VOCs	11.59	n/a	n/a	0.16
	CO	331.05	n/a	n/a	4.48
Turbine #1 (Natural gas)	PM	36.25	261	n/a	2.9
	SO _x	0.56	n/a	n/a	n/a
	NO _x	381.07	n/a	n/a	n/a
	VOCs	20.74	n/a	n/a	3.6
	CO	95.27	n/a	n/a	16.4
Turbine #2 (Natural gas)	PM	69.02	429	n/a	0
	SO _x	1.06	n/a	n/a	0
	NO _x	725.49	n/a	n/a	0.05
	VOCs	39.48	n/a	n/a	0
	CO	181.37	n/a	n/a	0.01
Turbine #3 (Natural gas)	PM	159.90	818	n/a	1.5
	SO _x	2.45	n/a	n/a	0.7
	NO _x	1680.78	n/a	n/a	33.3
	VOCs	91.48	n/a	n/a	1.8
	CO	420.20	n/a	n/a	8.3
Steam Unit 1 (Fuel oil #6)	PM	285.34	883	n/a	n/a
	SO _x	3326.56	4238	n/a	n/a
	NO _x	1892.82	n/a	n/a	n/a
	VOCs	21.47	n/a	n/a	n/a

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Unit	Pollutant	PTE (tpy)	Allowable ⁽¹⁾ (tpy)	Test Data ⁽³⁾ (tpy)	EI 1995 (tpy)
	CO	141.26	n/a	n/a	n/a
Turbine #1 (Fuel oil #2)	PM	48.49	265	n/a	n/a
	SOx	40.18	884	n/a	n/a
	NOx	555.15	n/a	n/a	n/a
	VOCs	13.49	n/a	n/a	n/a
	CO	38.18	n/a	n/a	n/a
Turbine #2 (Fuel oil #2)	PM	66.20	336	n/a	n/a
	SOx	54.86	1207	n/a	n/a
	NOx	757.99	n/a	n/a	n/a
	VOCs	18.42	n/a	n/a	n/a
	CO	52.13	n/a	n/a	n/a
Turbine #3 (Fuel oil #6)	PM	205.69	803	n/a	n/a
	SOx	2556.71	3749	n/a	n/a
	NOx	2355.02	n/a	n/a	n/a
	VOCs	57.23	n/a	n/a	n/a
	CO	161.95	n/a	n/a	n/a
Steam Units 2 (Coal)	PM	276.2 ⁽²⁾	837	276.2	132
	SOx	4871.4 ⁽²⁾	10044	4871.4	2267
	NOx	5139.2 ⁽²⁾	5859	5139.2	2701
	VOCs	20.93	n/a	n/a	15
	CO	174.38	n/a	n/a	125
Steam Units 3 (Coal)	PM	343.2 ⁽²⁾	837	343.2	126
	SOx	4017.7 ⁽²⁾	10044	4017.7	2049
	NOx	3749.8 ⁽²⁾	5859	3749.8	3329
	VOCs	20.93	n/a	n/a	17.2

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Unit	Pollutant	PTE (tpy)	Allowable ⁽¹⁾ (tpy)	Test Data ⁽³⁾ (tpy)	EI 1995 (tpy)
	CO	174.38	n/a	n/a	143.2
Diesel turbine startup engine	PM	0.93	4.5	n/a	n/a
	SOx	3	4.4	n/a	n/a
	NOx	46.4	n/a	n/a	n/a
	VOCs	1.3	n/a	n/a	n/a
	CO	12.1	n/a	n/a	n/a
Coal preparation plant	PM	4288	n/a	n/a	589.8
Limestone handling operations	PM	71	84	n/a	9
Cooling tower 1	PM	8	519	n/a	1.31
Cooling tower 2	PM	16	573	n/a	10.3
Cooling tower 3	PM	16	573	n/a	11.5

Note: ⁽¹⁾ The allowable emissions (from Articles 7 or 9 of the A.A.C.) in tpy are obtained assuming 8760 hours of operation per year.

⁽²⁾ PTE has been replaced with the test result.

⁽³⁾ Test data is an average of test results in 1995, 1996, and 1997.

Emissions from coal preparation plant and lime handling operations are aggregate of all operation emission points.

N/a Not available

The numbers in the PTE column were calculated by the Agency and do not reflect the PTE calculations submitted by AEPCO in its Class I Permit application, nor do they reflect all the physical or operational limitations on Apache Station emission sources.

IV. COMPLIANCE HISTORY

A. Inspections

Inspections are being regularly conducted on this source to ensure compliance with the permit conditions. Table 5 summarizes some of the recent inspections that have been

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conducted on the source and the results of the inspections.

Table 5: Inspection Results

Inspection Date	Type of Inspection	Results
June 16-17, 1996	Performance Test	Compliance tests for PM, SO _x , and NO _x were performed on units 2 and 3. Annual RATA was also completed. ESP lost 7-9 cabinets causing opacity to exceed the 20% limit. Excess emission was filed. The tests indicated compliance of the source with the applicable regulations.
August 3, 1995	40 CFR 75 Testing	RATA on the CEMs for certification for Unit 1 was observed. (Attached). The tests indicated compliance of the source with the applicable regulations.
May 16, 1994	Level 2	Opacity was between 0-5% from both the stacks. All CEMS were operating. ESP and SDAS were operating. (Attached)
March 8, 1994	Level 2	Opacity was between 5-10% from both the stacks.
January 13, 1994	Performance Test	Compliance tests for PM, SO _x , and NO _x were performed on units 2 and 3. A documented opacity exceedance (29%) occurred during the test on unit three. The tests indicated compliance of the source with the applicable regulations.
November 10, 1993	Level 2	Opacity reading from the stack was 6.04%.

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May 23, 1993	Performance Test	Compliance tests for PM, SO _x , and NO _x were performed on units 2 and 3. Opacity according to CEM was 7% and Method 9 was 6.25%. The tests indicated compliance of the source with the applicable regulations.
December 2, 1992	Performance Test	Compliance tests for PM, SO _x , and NO _x were performed on unit 2 burning coal. The tests indicated compliance of the source with the applicable regulations.
September 30-October 1, 1992	Performance Test	Compliance tests for PM, SO _x , and NO _x were performed on units 2 and 3 burning coal and natural gas respectively. The tests indicated compliance of the source with the applicable regulations.

AEPCO was issued a notice of violation by the U.S. EPA in 1992 for not obtaining a Class B permit prior to their discontinuing the routine use of their sulfur dioxide absorption systems on Units 2 and 3. AEPCO entered into a consent decree with the United States on America on April 14, 1993. The decree expired in 1994. Among other things, the consent decree required AEPCO to do the following:

1. Relocate the airheater sootblowers in Steam Unit 2 to direct the exhaust from the sootblowers through the inlet air side, so that the exhaust is recirculated through the units' respective electrostatic precipitator. (Installation Permit 031161)
2. Modify the ESP inlet ladder vanes to minimize ash buildup. (Installation Permit 031204)

B. Excess Emissions

Units 2 and 3 have reported excess visible emissions in the past two years (1996 and 1997) over a hundred times. The primary cause of excess visible emissions is the in-stack condensation which occurs because of the wetness of the flue gas exiting the wet limestone scrubber. Other causes include start-up/load ramping, shutdown, soot blowing, and air pollution control equipment malfunction. The Permittee remedied most of the excess emissions promptly by minimizing load ramping or repairing the malfunctioning equipment.

Of the total hours of excess opacity for unit 2 (499.9 hrs) in 1996 and 1997, 138.7 hrs. were attributed to startup/shutdown/malfunction and 265.3 hrs. were attributed to the moisture condensation in the stack. The rest of the hours (0.59% of the operating hours) resulted in

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valid opacity exceedances. Similarly for steam unit 3, of the total hours of excess opacity (175.8 hrs), 87 hrs. were attributed to startup/shutdown/malfunction and 81.8 hrs. were attributed to the moisture condensation in the stack. The rest of the hours (0.05% of the operating hours) resulted in valid opacity exceedances.

Units 2 and 3 have no reported case of excess emissions of NO_x in the last two years (1996 and 1997). Unit 2 reported excess emissions of SO₂ on 8/15/97, 8/16/97, and 8/17/97. The cause of these emissions was the air pollution control device (SDAS) malfunction. The other scrubber module was brought into operation till the problem was resolved. A report of the excess emissions in the last two years has been attached to this document.

C. Testing

The results of the three latest compliance tests have been summarized in Table 6. Results show that the units are in compliance with the applicable standards.

Table 6: Test Results

Date	Equipment Tested	Pollutant Tested	Tested Emission Rate	Allowable Emission Rate	Results
June 19-20, 1997	Unit 2	PM	0.033 lb/MMBtu	0.10 lb/MMBtu	Units were tested at full load when firing coal and passed for all the three pollutants.
		SO ₂	0.582 lb/MMBtu	0.80 lb/MMBtu	
		NO _x	0.614 lb/MMBtu	0.70 lb/MMBtu	
	Unit 3	PM	0.041 lb/MMBtu	0.10 lb/MMBtu	
		SO ₂	0.480 lb/MMBtu	0.80 lb/MMBtu	
		NO _x	0.448 lb/MMBtu	0.70 lb/MMBtu	
June 16-17, 1996	Unit 2	PM	0.046 lb/MMBtu	0.10 lb/MMBtu	Units were tested at full load when firing coal and passed for all the three pollutants.
		SO ₂	0.630 lb/MMBtu	0.80 lb/MMBtu	
		NO _x	0.539 lb/MMBtu	0.70 lb/MMBtu	
	Unit 3	PM	0.036 lb/MMBtu	0.10 lb/MMBtu	
		SO ₂	0.472 lb/MMBtu	0.80 lb/MMBtu	
		NO _x	0.465 lb/MMBtu	0.70 lb/MMBtu	
November 13-14, 1995	Unit 2	PM	0.027 lb/MMBtu	0.10 lb/MMBtu	Units were tested at full load when firing coal and passed for all the three pollutants.
		SO ₂	0.421 lb/MMBtu	0.80 lb/MMBtu	
		NO _x	0.500 lb/MMBtu	0.70 lb/MMBtu	
	Unit 3	PM	0.025 lb/MMBtu	0.10 lb/MMBtu	
		SO ₂	0.434 lb/MMBtu	0.80 lb/MMBtu	
		NO _x	0.480 lb/MMBtu	0.70 lb/MMBtu	

D. Compliance Certifications

After the issuance of this Part 70 permit, the Permittee will be required to submit compliance

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certifications every six months as indicated in Section VII of Attachment “A” of the permit. AEPCO has clearly specified in Section 5 of the permit application that it operates all emission units in compliance with applicable requirements and will continue to comply with all applicable requirements under the existing operating permits. In addition, AEPCO will comply with all applicable requirements that become effective during the permit term on a timely basis.

AEPCO has clearly specified in Section 5 of the permit application that it will submit an semi-annual compliance certification report which will identify the status of compliance. The semi-annual compliance certification will be signed by the responsible official ascertaining the truth, accuracy, and completeness of the information provided. The certification will include information pertaining to the methods used for determining the compliance status of the sources of emissions from AEPCO operations. The information will be based on monitoring results compiled over the reporting period as prescribed in the permit.

AEPCO has an allowance of 1597 tons of sulfur dioxide per year under the Acid Rain program for Steam Unit 2. Although EI data shown in Table 4 of this document indicates sulfur dioxide emissions in excess of the acid rain limit, AEPCO has proposed to tackle this issue at the appropriate time by either buying allowances from outside or by varying the unit operation, the fuel used, or the scrubber operation to meet the limit.

V. APPLICABLE REGULATIONS VERIFICATION

The Permittee has identified the applicable regulations that apply to each unit in its permit application. Table 7 summarizes the findings of the Department with respect to the regulations that apply to each emissions source. Those regulations identified as specifically not applicable to Apache Station for purposes of the permit shield are listed in Attachment “C” of the Class I permit. Installation Permit and other previous permit conditions are discussed under Section VI of this technical review document.

Table 7: Applicable Regulations Verification

Unit ID	Contract date	Control Equipment	Applicable Regulations	Verification
Steam Unit 1	8/62	None	A.A.C. R18-2-702.B A.A.C. R18-2-703.A A.A.C. R18-2-703.B A.A.C. R18-2-703.C.1 A.A.C. R18-2-703.E.1 A.A.C. R18-2-703.H A.A.C. R18-2-703.J A.A.C. R18-2-703.K 40 CFR 72 40 CFR 73 40 CFR 75	The contract-awarded date of this unit predates the enactment of the Act. Since the heat input is 851 MMBtu/hr (>250 MMBtu/hr), this unit is subject to R18-2-703. NOx standards are not applicable to this source because the start-up date is prior to May 30, 1972. For the same reason, the SO ₂ standard of 0.8 lb/MMBtu applies.

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Steam Units 2 & 3	8/28/74 for the steam units and the control equipment	Two ESPs and two SDAS	40 CFR 60.42(a) 40 CFR 60.43 (a) A.A.C. R18-2-903.1 A.A.C. R18-2-903.2 40 CFR 60.43 (c) 40 CFR 60.44(a) 40 CFR 60.44(b) 40 CFR 60.45(a) 40 CFR 60.45(c) 40 CFR 60.45(e) 40 CFR 60.45(f) 40 CFR 60.45(g) 40 CFR 60.46(a) 40 CFR 60.46(b) 40 CFR 60.46(c) 40 CFR 60.46(d) 40 CFR 72 40 CFR 73 40 CFR 75	The sulfur dioxide standard when burning coal is 0.8 lb/MMBtu heat input according to A.A.C. R18-2-903.1. The sulfur dioxide standard for co-firing fossil fuels is deleted by A.A.C. R18-2-903.2. In case where different requirements apply, the more stringent requirement shall apply. Please see Section on used oil in this document for CEMS operation exemption.
Gas Turbines 1, 2, and 3	#1: 1/61 #2: 8/71 #3: 7/73	None	A.A.C. R18-2-719.A A.A.C. R18-2-719.B A.A.C. R18-2-719.C.1 A.A.C. R18-2-719.E A.A.C. R18-2-719.F A.A.C. R18-2-719.H A.A.C. R18-2-719.I A.A.C. R18-2-719.J A.A.C. R18-2-719.K	The contract-awarded dates of these units are prior to October 3, 1977, and hence are not subject to 40 CFR 60, Subpart GG. These units are subject to an opacity standard of 40% and sulfur dioxide standard of 1.0 lb/MMBtu.
Coal Preparation Plant	3/21/75	Spray bars and baghouse on silos	40 CFR 60.252(c) and A.A.C. R18-2-702.B A.A.C. R18-2-730	Please see correspondence from AEPCO dated June 9, 1998, and August 18, 1998, explaining the applicability of Subpart Y and A.A.C. R18-2-730.
Limestone Preparation Plant	3/21/75	Bag filter on limestone storage bin	A.A.C. R18-2-702.B A.A.C. R18-2-722	The limestone handling plant at Apache is subject to particulate matter standard under A.A.C. R18-2-722.B.1 and the general visible emissions standards.
Cooling Towers 1, 2, and 3	9/25/74		A.A.C. R18-2-702.B A.A.C. R18-2-730.A.1 A.A.C. R18-2-730.A.2 A.A.C. R18-2-730.A.3	Since chromium-based water treatment chemicals are not used, the cooling towers are subject to the particulate matter, SO _x , and NO _x standards under A.A.C. R18-2-730 and the general visible emissions standard.

VI. PREVIOUS PERMITS AND CONDITIONS

A. Previous Permits

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Table 8: Previous Permits

Date Permit Issued	Permit No.	Application Basis
December 16, 1997 The effective date of this permit shall be the date the initial Title V permit becomes effective, or January 1, 2000, whichever is earlier	1000667	Significant Permit Revision to Permit No. 0302-84
May 5, 1993	031204	Installation Permit
April 23, 1993	031161	Installation Permit
July 3, 1990	1223	Installation Permit (Superseded IP 1202)
December 17, 1987	1202	Installation Permit
April 26, 1984	0302-84	Operating Permit

The Permittee has been operating the source in compliance with conditions under this permit as could be seen from the inspection reports in Section IV.A of this technical review document. The Class I permit will supercede all terms and conditions of previous operating permits, including permit 0302-84.

B. Previous Permit Conditions

a. Operating Permit 0302-84

This is the most recent operating permit issued to the source. Some of the relevant (for discussion purposes) terms of this permit are:

1. Permittee shall operate the facilities in compliance with A.A.C. R9-3-503.
2. All equipment, facilities, and systems used to achieve compliance with the terms and conditions of the operating permit shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions.
3. Permittee shall submit to the Director a written report of excess emissions of opacity, SO₂ and NO_x, including cause of emissions, actions taken to

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reduce emissions, and steps taken to prevent the recurrence of that episode.

4. Permittee shall not use high sulfur fuel oil unless Director approve the use of high sulfur fuel oil.
5. Permittee shall continue to investigate the cause of excessive visible emissions and implement the recommendations of the April 25, 1984 report. Progress in the abatement of excess emissions shall be reported in the quarterly report.

All the conditions listed above have been carried over in essence to the Part 70 renewal permit. Hence, the conditions in this permit are hereby being replaced by the corresponding conditions in the Part 70 renewal permit.

b. Installation Permit No. 1202

This permit allowed the modification of Unit 3 boiler to accommodate the combustion of natural gas as the major fuel in the boiler. Some of the relevant terms of this permit are:

1. Permittee shall test Unit 3 within 60 days after modification and has achieved the capability to operate at its maximum heat rate, but no later than 180 days of initial startup for NOx emissions.
2. Permittee shall notify the following:
 - a. Date of commencement of construction/modification;
 - b. Date of completion of modification;
 - c. Date of startup after completion of modification; and
 - d. Date of attainment of maximum heat rate.
3. Permittee shall include within its quarterly reports, an attachment specifying those time periods when the unit burned natural gas as its main fuel.

c. Installation Permit No. 1223

On September 22, 1988, AEPCO requested a change to Permit No. 1202. AEPCO requested the modification approved for Unit 3 to be approved for Unit 2 for its best interest. A new installation permit no. 1223 was issued granting the modification of Unit 2 to accomodate combustion of natural gas. All the permit terms were carried over from Permit no. 1202. Attachment "B" summarizing the maximum emission rates allowable while burning natural gas and coal separately was added to this permit.

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ADEQ no longer has the maximum allowable emissions tables as an attachment to their permits. The emission limits were not required by the SIP or the state's NSR program. The emission limits were not placed to protect the NAAQS. Rather, these number were the source's potential to emit based on projected load. This table will be deleted as part of this Part 70 renewal. All the conditions listed above have been carried over in essence to the Part 70 renewal permit. Hence, the conditions in this permit are hereby being replaced by the corresponding conditions in the Part 70 renewal permit.

d. Installation Permit No. 031161

This permit allowed the modification of Unit 3 boiler to accommodate the combustion of natural gas as the major fuel in the boiler. Some of the relevant conditions of this permit are:

1. AEPCO shall install the natural gas burners in Unit 3 in compliance with the A.A.C R18-2-503.
2. AEPCO shall not allow or cause to be discharge into atmosphere from the Unit 3 stack the following pollutants in excess of the following limits on a one-hour average except during startup, shutdown, or malfunction as defined in Civil Action No. 92-383 TUC RMB:

NO_x = 0.70 lb/MMBtu (when burning coal, oil, or cofiring coal and natural gas) and 0.20 lb/MMBtu (when burning natural gas)

SO₂ = 0.80 lb/MMBtu (when burning coal, oil, or cofiring coal and natural gas)

PM: $E = 1.02Q^{0.769}$

3. AEPCO shall not allow or cause to be discharge into atmosphere from the Unit 3 stack any gases which exhibit greater than 20% opacity except during startup, shutdown, or malfunction as defined in Civil Action No. 92-383 TUC RMB.
4. AEPCO shall perform initial performance test within 60 days of achieving maximum heat rate but no later than 180 days after initial startup after modification. Subsequent tests shall be conducted at least on an annual basis for PM, SO₂, and NO_x.
5. AEPCO shall maintain and operate CEMS for measuring NO_x, SO₂, CO₂, and opacity. These shall meet the performance specifications 2 (for NO_x and SO_x), 3, and 1 of 40 CFR 60 Appendix B respectively.

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6. AEPCO shall submit a written report of all excess emissions on a quarterly basis.
7. AEPCO shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all performance evaluations, calibration checks, adjustments, and maintenance performed on the continuous monitoring system and monitoring devices, and all other information required by 40 CFR 60 Appendix B, in a permanent form suitable for inspection for at least two years after.
8. AEPCO shall perform daily calibration error checks for NO_x, SO₂, CO₂, and opacity.
9. AEPCO shall perform complete CEM system inspection daily including the following.
 - a. Chart recorder
 - b. Data loggers
 - c. Calibration gas
 - d. Sample dryer/conditioner
 - e. Vacuum pumps
 - f. Opacity analyzer
10. AEPCO shall perform bi-weekly preventative maintenance on gas sampling probes and verify critical orifice performance and recalibrate analyzers.
11. AEPCO shall change opacity transmissiometer blower filters every month.
12. AEPCO shall perform cylinder gas audit as per 40 CFR 60, Appendix F on a quarterly basis and manually calibrate opacity monitors.
13. AEPCO shall clean and adjust analyzers, clean umbilical and sample lines, and service zero-air scrubber on a semi-annual basis.
14. AEPCO shall perform clear-stack alignment on opacity transmissiometers and replace solenoids on sample conditioner on an annual basis.
15. AEPCO shall compare analyzer performance against compliance test each year. Acceptance criteria will be equivalent to 40 CFR 60, Appendix B, Specifications 2 and 3. If an analyzer exceeds acceptance criteria, a cylinder gas audit (CGA) shall be performed immediately, and adjustments and repairs made immediately.

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16. AEPCO shall burn only natural gas, coal, or fuel oil in Unit 3. Alternate fuels shall not be fired simultaneously unless CEMS are operating.
17. AEPCO shall notify ADEQ and EPA before use of fuel oil as a primary alternative fuel.
18. Amount of fuel burned and the sulfur/nitrogen of the fuel burned shall be recorded in a permanent record for two years.
19. Coal consumed in Unit 3 shall be sampled for moisture, ash, sulfur content and gross calorific value according to ASTM methods on each train load. The coal analysis shall be recorded in a permanent record for years.
20. AEPCO shall continuously operate and maintain the FGD and ESP systems in accordance with Civil Action No. 92-383 TUC RMB while firing coal. Controls shall be fully operational upon startup.

Although Installation Permit No. 031161 lists A.A.C. R18-2-503 as the applicable requirement for the Steam Unit No. 2, it has been determined with the help of the date the contract was awarded that this unit is subject to 40 CFR 60 Subpart D. The installation permit conditions are hereby revised to include 40 CFR 60, Subpart D requirements through this Part 70 renewal process.

All the other conditions listed above have been carried over in essence to the Part 70 renewal permit. Hence, the conditions in this permit are hereby being replaced by the corresponding conditions in the Part 70 renewal permit.

e. Installation Permit 031204

This permit allowed AEPCO to modify the ESP inlet ladder vanes on steam units 2 and 3 in compliance with A.A.C. R18-2-503 and Consent Decree Civil Action No. 92-0383 TUC RMB. This permit is similar to Permit No. 031161 and addresses both steam units 2 and 3 whereas Permit No. 031161 addresses only unit 3. Attachment "C" of this permit gives the maximum allowable emission rates from the steam units when firing coal and natural gas separately.

Although Installation Permit No. 031204 lists A.A.C. R18-2-503 as the applicable requirement for the Steam Unit Nos. 2 and 3, it has been determined with the help of the date the contract was awarded that these units are subject to 40 CFR 60 Subpart D. The installation permit conditions are hereby revised to include 40 CFR 60, Subpart D requirements through this Part 70 renewal process. ADEQ no longer has the maximum allowable emissions tables as an attachment to their permits. The emission limits were not required by the SIP or the state's NSR program. The emission limits were not placed to protect the NAAQS. Rather, these number were the source's potential to emit based on

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projected load. This table will be deleted as part of this Part 70 renewal.

All the other conditions listed above have been carried over in essence to the Part 70 renewal permit. Hence, the conditions in this permit are hereby being replaced by the corresponding conditions in the Part 70 renewal permit.

VII. PERIODIC MONITORING

A. *Steam Units 2 and 3*

Opacity: The steam units are subject to an opacity standard of $< 20\%$ except for one six-minute period per hour of not more than 27% opacity. The units have had problems in the past with opacity mainly during load ramping and because of in-stack opacity condensation. Please see the Section on Excess Emissions in this technical remarks document. The Permittee is required to operate a continuous monitoring system for opacity. This monitor will be used as the periodic monitoring method. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specification 1. In addition to the periodic monitoring using continuous opacity monitors, the Permittee is required to perform an annual EPA Reference Method 9 test on the stacks of each unit.

PM: The steam units are subject to a standard of 0.10 lb/MMBtu in 40 CFR 60.42(a)(1). Compliance test results indicate that the units are able to meet the standard. Please see the Section on Testing in this technical remarks document. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit. This permit requires a stack test every year plus periodically monitoring stack opacity to fulfill the periodic monitoring requirements for particulate matter emissions. Although no data is available to directly correlate opacity to particulate matter emissions, doing so would at least indicate potential problems with the air pollution control device. If corrective actions are taken to rectify the problems associated with the pollution control device, then compliance can be inferred on the basis that the source operates its pollution control equipment in a manner consistent with good air pollution control practices. The source proposed a 24-hr rolling average opacity of 15% beyond which corrective actions need to be implemented. The opacity limit is 20% for this source. Opacity above 15% but less than 20% does not hold the source in violation of the particulate matter standard, but merely requires the source to identify and alleviate the problem by taking corrective actions to reduce the opacity to less than 15% . However, not taking corrective actions could potentially hold the source in violation of the permit terms.

SO₂: The source is subject to the sulfur dioxide standard of 0.8 lb/MMBtu heat input in A.A.C. R18-2-903.1 while burning coal or co-firing coal and natural gas. Compliance test results indicate that the units are able to meet the standard. Please see the Section on Testing in this technical remarks document. Table 4 compares

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the PTE, allowable emissions, test data, and actual emissions for this unit. We notice that the allowable emissions are greater than the potential to emit. The Permittee is required to operate a continuous emissions monitoring system (CEMS) for recording emissions of sulfur dioxide. The CEMS will be used as the periodic monitoring method. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A and B. In addition to the periodic monitoring using continuous emission monitors, the Permittee is required to perform an annual EPA Reference Method 6 or 6C test on the stacks of each unit.

NOx: The source is subject to the NOx standard of 0.70 lb/MMBtu heat input in 40 CFR 60.44(a)(3) while burning coal and 0.20 lb/MMBtu while burning natural gas. It is subject to the standard under 40 CFR 60.44(b) when co-firing coal and natural gas. Compliance test results indicate that the units are able to meet the standard comfortably. Please see the Section on Testing in this technical remarks document. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit. The Permittee is required to operate a continuous emissions monitoring system (CEMS) for recording emissions of nitrogen oxides. The CEMS will be used as the periodic monitoring method. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A and B. In addition to the periodic monitoring using continuous emission monitors, the Permittee is required to perform an annual EPA Reference Method 7 or 7E test on the stacks of each unit.

B. Steam Unit 1/Combined Cycle Operation of Steam Unit 1 and Gas Turbine No. 1

Steam Unit 1 and Gas Turbine 1 have the ability to be operated in combined cycle operation or simple cycle operation. Under combined cycle operation, exhaust from Gas Turbine 1 is used to provide intake air to the Steam Unit 1 windbox. This is done to increase the load output and efficiency of the system.

It is normal operation for Unit 1 and GT1 to operate in combined cycle. However, both units are capable of running individually. When GT1 is run independent of Steam Unit 1, the air flow control dampers direct exhaust to the atmosphere instead of the Steam Unit 1 intake airstream. If Steam Unit 1 is run without GT1, the flow control dampers from the turbine are closed and the unit solely relies on the unit's two forced draft fans to provide intake air to the windbox.

Opacity: The steam unit is subject to the opacity standard of < 40% under the general visible emissions rule in A.A.C. R18-2-702.B. This unit burns natural gas primarily and is capable of burning fuel oil nos. 2 through 6.

Natural gas: Natural gas is a clean burning fuel and inspections (see table under Section IV.A of this technical remarks section) indicate that there have been no opacity problems with this unit. Hence, no monitoring is required when burning natural gas.

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Fuel oil: Since this unit meets the definition of a natural gas-fired unit under Part 72, it is not required to have a continuous opacity monitor. However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

1. When fuel oil is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.
2. When fuel oil is burned continuously for a time period > 168 hours, then for each 168 period one EPA Method 9 reading is required.

The permittee is also required to monitor and record the number of hours fuel oil is burned continuously in the unit. The time period of 48 hours was established through meetings with the stakeholders. This time period is of particular importance to the stations where there may not be a certified opacity observer to conduct observations during weekends, holidays, etc.

PM: The unit is also subject to the particulate matter emissions standard in A.A.C. R18-2-703.C.1. This unit burns natural gas primarily and is capable of burning fuel oil nos. 2 through 6.

Natural gas: Natural gas is a clean burning fuel and results in negligible particulate matter emissions as demonstrated by engineering calculations and tabulated under the PTE column in Table 4. Therefore, it was determined that a verification through engineering calculation would fulfill the requirements for periodic monitoring when burning natural gas.

Fuel oil: However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit. The permittee is also required to monitor the following information about the fuel found in the contractual agreement with the liquid fuel vendor:

1. Heating value; and
2. Ash content.

Ash content is not an accurate measure but is a good indicator of particulate matter emissions, and monitoring this would help the agency to “ballpark” the particulate matter emissions. No engineering estimation using ash content is prescribed in the permit

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since it could be interpreted to incorrectly correlate particulate matter emissions to ash content only. Permittee is required to keep on record a copy of the contractual agreement. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

SO₂: The steam unit is subject to the sulfur dioxide standard in A.A.C. R18-2-703.E.1 since the unit was placed in commercial operation in 1963. This standard applies only when the unit burns fuel oil. There is no standard when the unit burns natural gas.

Fuel oil: When fuel oil is burned, the Permittee is required to keep on record the fuel supplier certification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and
3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SO₂ emissions using the information from above according to the following equation for any change in (2) above:

$$\text{SO}_2 \text{ (lb/MMBtu)} = 2.0 \times [(\text{Weight percent of sulfur}/100) \times \text{Density (lb/gal)}] / [(\text{Heating value (Btu/gal)}) \times (1 \text{ MMBtu}/1,000,000 \text{ Btu})]$$

Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

NO_x: The steam unit was placed in commercial operation in 1963. The nitrogen oxides standard under A.A.C. R18-2-703.I does not apply to this unit. Although there is no applicable standard for nitrogen oxides, this source being subject to Title IV requirements, is required to operate, maintain, and calibrate a CEMS for NO_x. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

C. *Hot Water Heater and Space Heaters*

Opacity: The heaters are subject to the opacity standard of < 15% in A.A.C. R18-2-724.J. The hot water heater burns propane and the space heaters burn natural gas.

Natural gas and Propane: Natural gas and propane are clean burning fuels and usually do not pose visible emissions problem. Hence, no monitoring is required when burning

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natural gas and propane.

PM: The units are also subject to the particulate matter emissions standard in A.A.C. R18-2-724.C.1.

Natural gas and Propane: Natural gas and propane are clean burning fuels and result in negligible particulate matter emissions as demonstrated by engineering calculations. Therefore, it was determined that a verification through engineering calculation would fulfill the requirements for periodic monitoring when burning natural gas and propane.

SO₂: There is no applicable standard and hence no monitoring is required.

NO_x: There is no applicable standard and hence no monitoring is required.

D. Gas Turbine Nos. 1, 2, and 3 and Gas Turbine 1 Startup Engine

Opacity: The turbines are subject to the opacity standard of < 40% in A.A.C. R18-2-719.E. Gas turbine Nos. 1, 2, and 3 burn natural gas primarily and are capable of burning fuel oil no. 2. Gas turbine No. 3 can burn fuel oil nos. 2 through 6.

Natural gas: Natural gas is a clean burning fuel and usually does not pose a visible emissions problem. Hence, no monitoring is required when burning natural gas.

Fuel oil: However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

1. When fuel oil is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.
2. When fuel oil is burned continuously for a time period > 168 hours, then for each 168 hour period one EPA Method 9 reading is required.

The permittee is also required to monitor and record the number of hours fuel oil is burned continuously in the units. The time period of 48 hours was established through meetings with the stakeholders. This time period is of particular importance to the stations where there may not be a certified opacity observer to conduct observations during weekends, holidays, etc.

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PM: The units are also subject to the particulate matter emissions standard in A.A.C. R18-2-719.C.1.

Natural gas: Natural gas is a clean burning fuel and results in negligible particulate matter emissions as demonstrated by engineering calculations and tabulated under the PTE column in Table 4. Therefore, it was determined that a verification through engineering calculation would fulfill the requirements for periodic monitoring when burning natural gas.

Fuel oil: However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit. The permittee is also required to monitor the following information about the fuel found in the contractual agreement with the liquid fuel vendor:

1. Heating value; and
2. Ash content.

Ash content is not an accurate measure but is a good indicator of particulate matter emissions, and monitoring this would help the agency to "ballpark" the particulate matter emissions. No engineering estimation using ash content is prescribed in the permit since it could be interpreted to incorrectly correlate particulate matter emissions to ash content only. Permittee is required to keep on record a copy of the contractual agreement. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit. It can be seen that the PTE is only 19% of the allowable emissions in the case of gas turbine no. 1, 20% in the case of gas turbine no. 2, and 26% in the case of the gas turbine no. 3.

SO₂: The gas turbines are subject to the sulfur dioxide standard in A.A.C. R18-2-719.F. This standard applies only when the unit burns fuel oil. A.A.C. R18-2-719.J requires reporting of all periods when the sulfur content of the fuel exceeds 0.8 percent by weight and this has been included in the permit as an emission limitation.

Natural gas: "Pipeline-quality" natural gas has to conform to standards approved by the Federal Energy Regulatory Commission (FERC). One of the FERC standards limits the sulfur content in the gas to less than 5 grains/100 scf (which is equivalent to 0.017 weight percent of sulfur). Another standard specifies that the heating value must be greater than or equal to 967 Btu per cubic foot. AEPCO runs the gas turbines with fuel drawn from their pipeline, and therefore maintaining a copy of the FERC

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approved Tariff agreement on-site is an adequate means of complying with the monitoring requirements for the particulate, opacity and fuel use standards.

Fuel oil: When fuel oil is burned, the Permittee is required to keep on record fuel supplier certification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and
3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SO₂ emissions using the information from above according to the following equation for any change in the conditions above:

$$\text{SO}_2 \text{ (lb/MMBtu)} = 2.0 \times [(\text{Weight percent of sulfur}/100) \times \text{Density (lb/gal)}] / [(\text{Heating value (Btu/gal)}) \times (1 \text{ MMBtu}/1,000,000 \text{ Btu})]$$

Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

NOx: Although there is no applicable standard for nitrogen oxides, the permittee is required to monitor the dates and hours of operation of the engines for the purposes of testing. The source has been required to be tested once during the term of the permit according to the schedule given below, if necessary. The turbines have been determined to cross the major threshold (100 tpy) according to the following schedule:

1. Gas Turbine 2: When operated for 1200 hours on a twelve month rolling total basis; and
2. Gas Turbine 3: When operated for 525 hours on a twelve month rolling total basis.

The hours were derived assuming natural gas is burned in the units. Gas Turbine No.1 mostly operates in the combined cycle mode and NOx emissions are monitored at the exit of Steam Unit 1 stack. Hence, no testing has been required for Gas Turbine No. 1. Gas turbine no. 1 start-up diesel engine cannot emit more than 100 tons in a year and hence a test is not required for it. The tests will be conducted when burning the primary fuel. The permit requires the permittee to report the dates and hours of operation of the turbines semi-annually, during the six months prior to the date of report. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

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E. Cooling Towers 1, 2, and 3

- Opacity: The cooling towers are subject to the opacity standard of < 40% in the general visible emissions rule under A.A.C. R18-2-702.B.
- PM: The units are also subject to particulate matter emissions standard in A.A.C. R18-2-730.A.1. The particulate matter emissions from the cooling towers is negligible compared to the potential to emit as could be seen from Table 4 in Section III of this document. The PTE is only 2-3% of the allowable emissions and hence there is no need for monitoring requirements in the permit. Also, as physical constraints make particulate matter testing infeasible, ADEQ is not requiring performance tests on the cooling tower.

F. Coal Preparation Plant

Units Subject to 40 CFR 60, Subpart Y (Railcar Unloading Feeder Nos. 1 through 8, Screen Feeders, Crusher, Screening Units, Conveyor Nos. 1, 2, 6, 7, 8, and 9, Transfer Chute from Conveyor No. 1 to Conveyor No. 6, and Transfer Hopper Downstream of Crusher)

- Opacity: The units are subject to the 20% opacity standard in 40 CFR 60, Subpart Y. The permittee is required to make a weekly survey of the visible emissions from the points listed above. The permittee is required to create a record of the date on which the survey was taken, the name of the observer, and the results of the survey. If the visible emissions do not appear to exceed the standard, the permittee would note in the record that the visible emissions were of low opacity, and it did not require a Method 9 to be performed.

If the permittee finds that on an instantaneous basis the visible emissions could be in excess of 20% opacity, then he is required to make a six-minute Method 9 observation. If this observation indicates opacity in excess of 20% then the permittee is required to report it as excess emissions. In addition, the Permittee is required to adjust the process equipment or process control equipment to bring the opacity below 20%. If the permittee finds that the visible emissions is less than 20% opacity, then the permittee is required to record the source of emission, date, time, and result of the test.

Units Subject to A.A.C. R18-2-730 (Conveyor Nos. 3, 4a, 4b, 5-2, and 5-3, Feeder Nos. 9 through 13, Transfer Chute from Conveyor No. 1 to Conveyor No. 2, Enclosed Transfer Chute Nos. 4A and 4B, Coal Silos, Transfer Chute from Conveyor No. 1 to Conveyor Nos. 4a and 4b)

- Opacity: The units are subject to the 40% opacity standard in A.A.C. R18-2-730. The open coal storage pile at Apache is subject to 40% opacity standard under A.A.C. R18-2-610. The permittee is required to make a weekly survey of the visible emissions

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from the points listed above. The permittee is required to create a record of the date on which the survey was taken, the name of the observer, and the results of the survey. If the visible emissions do not appear to exceed the standard, the permittee would note in the record that the visible emissions were of low opacity, and it did not require a Method 9 to be performed.

If the permittee finds that on an instantaneous basis the visible emissions is in excess of 40% opacity, then he is required to make a six-minute Method 9 observation. If this observation indicates opacity in excess of 40% then the permittee is required to report it as excess emissions. In addition, the Permittee is required to adjust the process equipment or process control equipment to bring the opacity below 40%. If the permittee finds that the visible emissions is less than 40% opacity, then the permittee is required to record the source of emission, date, time, and result of the test.

PM: The source is subject to the particulate matter standard in A.A.C. R18-2-730.A.1.b. The permittee is required to maintain and operate the baghouse on the silos in accordance with the manufacturer's specification. Permittee is also required to hold these specifications on file. Emissions related maintenance work need to be recorded.

G. Limestone Handling Plant

Opacity: The limestone handling plant is subject to the 40% opacity standard. The permittee is required to make a weekly survey of the visible emissions from the entire limestone plant including all the enclosed transfer points, the exposed transfer points, the storage pile, and the bag filter. The permittee is required to create a record of the date on which the survey was taken, the name of the observer, and the results of the survey. If the visible emissions do not appear to exceed the standard, the permittee would note in the record that the visible emissions were of low opacity, and it did not require a Method 9 to be performed.

If the permittee finds that on an instantaneous basis the visible emissions is in excess of 40% opacity, then he is required to make a six-minute Method 9 observation. If this observation indicates opacity in excess of 40% then the permittee is required to report it as excess emissions. In addition, the Permittee is required to adjust the process equipment or process control equipment to bring the opacity below 40%. If the permittee finds that the visible emissions is less than 40% opacity, then the permittee is required to record the source of emission, date, time, and result of the test.

PM: The source is subject to the particulate matter standard in A.A.C. R18-2-730.A.1. a. The permittee is required to maintain and operate the limestone bin bag filter in accordance with the manufacturer's specification. Permittee is also required to hold

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these specifications on file. Emissions related maintenance work need to be recorded.

H. Non-point sources

The standards in Article 6 are applicable requirements for non-point sources. The following sources will be monitored:

1. Driveways, parking areas, vacant lots
2. Unused open areas
3. Open areas (Used, altered, repaired, etc.)
4. Construction of roadways
5. Material transportation
6. Material handling
7. Storage piles
8. Stacking and reclaiming machinery at storage piles

All of these areas must comply with the opacity limitation of 40%. The control measures for controlling particulate matter emissions from these sources are listed in AEPCO's Class I permit. AEPCO has indicated in the application, that rare instances of open burning may occur. The condition in the permit directs AEPCO to obtain a permit from ADEQ, or the local officer in charge of issuing burn permits.

Monitoring and recordkeeping requirements for these non-point sources include a record of the date and type of activity performed and the type of controls used. Also, monitoring requirements for the applicable open burning rule may be satisfied by keeping all open burn permits on file.

I. Other Periodic Activities

1. Abrasive Sand Blasting

AEPCO has indicated in the permit application that there might be a few occasions on which abrasive sand blasting activities are conducted on-site. R18-2-726 and R18-2-702 (B) are applicable requirements, and as such have to be included in the permit. It was decided to prescribe minimal monitoring requirements for this activity.

2. Spray Painting

AEPCO has indicated in the permit application that there might be a few occasions on which spray painting activities are conducted on-site. R18-2-727 and R18-2-702(B) are applicable requirements, and as such, have to be included in the permit. R18-2-727(A) and R18-2-727(B) are included in the approved State Implementation Plan (SIP). R18-2-727(C) and R18-2-727(D) are also a part of the approved SIP. They are present in the definitions section of the SIP as R9-3-101.117. EPA

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approved SIP provision R9-3-527.C is not present in the amended rule. However, R9-3-527.C is an applicable requirement, and is federally enforceable till the current State SIP is approved by the EPA. It was decided to prescribe minimal monitoring requirements for this activity.

3. Mobile Sources

The Permittee has been required to keep a record of all emissions related maintenance activities performed on Permittee's mobile sources stationed at the facility as per manufacturer's specifications for the purposes of monitoring and recordkeeping.

4. Asbestos Demolition/Renovation

The Permittee has been required to keep a record of all required paperwork on file for the purposes of monitoring and recordkeeping. The required paperwork includes "NESHAP Notification for Renovation and Demolition Activities" form and all supporting documents.

5. Nonvehicle Air Conditioner Maintenance and/or Services

The Permittee has been required to keep a record of all paperwork required by the applicable requirements of 40 CFR 82 - Subpart F on file for the purposes of monitoring and recordkeeping.

J. Used Oil Fuel

The Permittee has stated in the application that it expects to burn no more than 20,000 gallons per year of used oil fuel either in Steam Units 1, 2, or 3. The emissions from the burning of used oil fuel have been calculated using the characteristics of fuel oil no. 6. The heating value has been assumed to be 145,000 Btu/gal.

Maximum annual used oil fuel consumption	= 20,000 gal.
Heating value of used oil fuel	= 145,000 Btu/gal
Maximum heat input due to used oil fuel	= 2900 MMBtu/yr

CO Emissions	= (5 lb/1000 gal) x 20000 gal/yr
	= 0.05 tpy

NOx Emissions	= (67 lb/1000 gal) x 20000 gal/yr
	= 0.67 tpy

SO ₂ Emissions	= (117.5 lb/1000 gal) x 20000 gal/yr
	= 1.17 tpy

PM10 Emissions	= (10.1 lb/1000 gal) x 20000 gal/yr
	= 0.1 tpy

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$$\begin{aligned}\text{VOC Emissions} &= (0.76 \text{ lb/1000 gal}) \times 20000 \text{ gal/yr} \\ &= 0.0076 \text{ tpy}\end{aligned}$$

Just to give an idea of the quantity of emissions from the co-firing used oil to the reader, a comparison of the emissions from the units due to the used fuel oil usage and emissions from the 345-HP emergency diesel generator (an insignificant activity) is given below:

Table 9: Comparison of Emissions from Emergency Generator and Used Oil Fuel Usage

Pollutant	Emissions from Emergency Diesel Generator (tpy)	Emissions from Used Oil Fuel Usage in the Steam Units 1, 2, or 3 (tpy)
CO	5.2	0.05
NO _x	25.1	0.67
SO ₂	2.9	1.17
PM10	0.1	0.1
VOC	0.3	0.0076

From the above table it can be seen that the emissions from burning 20,000 gal/yr used oil are less than those from an activity that has been deemed insignificant. The emissions of other compounds like arsenic, lead, cadmium, chromium, and PCBs are limited by A.R.S. 49-801 and 802.

VIII. TESTING REQUIREMENTS

A. Steam Units 2 and 3

AEPCO is required to perform annual performance tests for opacity, particulate matter, SO₂ and NO_x in accordance with 40 CFR Part 60, Subpart D. Installed CEMS will be used as the periodic monitoring method.

B. Gas Turbines

The permittee is required to test each unit for conventional air pollutants that are emitted in quantities above 100 tons in a year based on the schedule given in Section VII.D of this document. The reasons for this test are as follows:

1. the test will have a direct impact on the annual emission fee;
2. the test will be the basis for any future modification; and
3. the test will help to get a clearer picture of the actual emissions from major sources in Arizona. While emission factors play an important role in the air pollution control program, they do not yield reliable data unless they are either developed directly from the emission unit in question or substitutes for a proven mass-balance

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relationship. Thus, testing would provide valuable information.

C. Coal Preparation Plant

An initial opacity test has been required to be performed at the coal preparation plant.

IX. INSIGNIFICANT ACTIVITIES

The following activities have been deemed insignificant:

Table 10: Insignificant Activities

S.No.	Insignificant Activities Sources	Determination	Comments
1	345-hp Emergency Caterpillar Diesel Generator, Model SR-4, S/N 90U 1386	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.h
2	Gas-fired Space Heaters	No	Subject to A.A.C. R18-2-724
3	Analytical Laboratory	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.i
4	UA Research Project	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
5	2,060-gallon Sodium Hypochlorite Storage Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
6	3,070-gallon Phosphonate/Tolytriazole Storage Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
7	1,890-gallon Phosphonate/Tolytriazole Storage Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
8	5,000-gallon Sulfuric Acid Storage Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
9	15,000-gallon Sulfuric Acid Storage Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
10	200-gallon Sodium Bromide Storage Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
11	300-gallon Phosphate Solution Storage Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

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12	200-gallon Phosphate Solution Storage Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
13	Chemical Storage	Yes	All chemicals not listed in 40 CFR 68.13 and those chemicals that are listed in 40 CFR 68.13 but stored in quantities less than threshold quantities are insignificant and those that do not have any applicable requirements under the Act or the Arizona Revised Statutes.
14	160,000-gallon Absorbent Feed Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
15	38,100-gallon Limestone Reagent Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
16	Equipment Wash Facility Propane Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
17	Firefighter Training Area Propane Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
18	Natural Gas Piping System	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
19	10,000-gallon Diesel AST	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
20	300-gallon 345-HP Generator Diesel AST	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
21	500-gallon Portable Diesel AST	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
22	500-gallon Partitioned Gasoline/Diesel Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
23	500-gallon Gas Turbine Supply Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
24	5,000,000-gallon Fuel Oil Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
25	1,000,000-gallon Fuel Oil Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

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26	Lube Oil Storage	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
27	5,000-gallon Used Oil AST	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
28	10,000-gallon Gasoline AST	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
29	Fuel Oil Piping System	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
30	Used Oil Satellite Collection Areas	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
31	Used Oil/RCRA/TSCA Waste Accumulation Area	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
32	5,000-gallon Caustic Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
33	1,890 Anionic Polymer Storage Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
34	Tol Oil Pitch & Humectin Storage Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
35	21,000-gallon BCM tanks (4)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
36	6,000-gallon BCM tanks (4)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
37	Steam Unit 2 Boiler Blowdown Tank (C-F System)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
38	Steam Unit 3 Boiler Blowdown Tank (C-F System)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
39	192,000-gallon Condensate Storage Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
40	45,000-gallon Condensate Storage Tanks (2)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
41	250,000 Treated Water Tank	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

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42	Septic Tank/Leach Field System	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
43	Office and Administrative Facilities	Yes	Not a source of air emissions
44	Office and Administrative Activities	Yes	Not a source of air emissions
45	Groundskeeping Activities	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.a
46	GK Equipment	No	Subject to A.A.C. R18-2-801
47	Herbicide/Pesticide Use	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
48	Firefighter Training Area	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
49	Open Burning	No	Subject to A.A.C. R18-2-602
50	Emergency Flares	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
51	Road Maintenance/ Construction	No	Subject to A.A.C. R18-2-605
52	Unpaved Road Use	No	Subject to A.A.C. R18-2-605
53	Paving Operations	No	Subject to A.A.C. R18-2-605
54	Road Sanding	No	Subject to A.A.C. R18-2-605
55	Street/Parking Lot Striping	No	Subject to A.A.C. R18-2-605
56	Passenger Vehicle Use	No	Subject to A.A.C. R18-2-604
57	Kitchen/Break-room Facilities	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

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58	Cleaning Equipment	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
59	Land Development Activities	No	Subject to A.A.C. R18-2-604
60	Unit Maintenance/Repair Activities	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
61	Lubricant Coating Operations	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
62	Medical Activities	Yes	Not a source of air emissions
63	Manually Operated Tool Use	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.f
64	Emission Sampling Equipment	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
65	Individual Components of Process Equipment	No	Subject to the applicable standards of the process.
66	Unit Testing	No	Subject to the applicable standards of the process.
67	Process Equipment Seals, Valves and Flanges	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
68	Brazing, Soldering, or Welding Operations	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
69	Battery Recharging	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
70	Aerosol Can Use	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
71	Plastic Pipe Welding	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
72	Acetylene, Butane, and Propane Torches	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
73	Structure surface painting	No	Subject to A.A.C. R18-2-727.B.1

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74	Steam Vents, Condenser Vents, and Boiler Blowdown	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
75	Portable Steam Cleaning Equipment	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
76	Blast-cleaning Equipment	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
77	Combustion Waste Surface Impoundment	No	Subject to A.A.C. R18-2-607
78	Cooling Tower Blowdown Pond	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
79	Coal Storage Pile Runoff Retention Basin	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
80	Pump/Motor Oil Reservoirs	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
81	Transformer Vents	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
82	Lubricating System Reservoirs	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
83	Hydraulic System Reservoirs	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
84	Adhesive Use	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
85	Caulking	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
86	Electric Motors	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
87	Cathodic Protection Systems	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
88	Corona	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
89	Nonprocess Production of Hot/Chilled Water Using Electricity	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

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90	Safety Devices	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
91	Soil Gas Sampling	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
92	Filter Draining	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
93	Heavy Equipment Maintenance Shop	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
94	Station Transformers	Yes	Not a source of air emissions
95	Circuit Breakers	Yes	Not a source of air emissions
96	Generation Unit Gas Vents	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
97	Flammable Product Storage Cabinets	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
98	Solvent Degreasing Basins	No	Subject to A.A.C. R18-2-730
99	Landfill Operations	No	Subject to A.A.C. R18-2-730
100	Coal Feeder Cleaning	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
101	"Hot" Coal Handling	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
102	Test Gases and Bottled Gases	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
103	Storm Water Systems Including Non-point Sumps and Open or Covered Drainage Troughs from Process Areas for Rainwater Handling.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

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104	Chemical Spills less than Reportable Quantities	No	Subject to appropriate regulations under the Act or the Arizona Revised Statutes.
105	Open Containers	No	Subject to appropriate regulations under the Act or the Arizona Revised Statutes.
106	Gasoline and Fuel Oil Transfer and Dispensing	No	Subject to A.A.C. R18-2-730.

X. ADDITIONAL INFORMATION REQUESTED

The Permittee submitted the Title V permit application on February 1, 1995. The application was deemed incomplete and an incompleteness letter was sent out on March 31, 1995. After meeting with the ADEQ staff on May 2, 1995, AEPCO sent additional information requested through its mail of June 30, 1995, to the Department. The application was deemed complete on July 26, 1995. AEPCO made several changes to its permit application through its letters of September 1, 1995, and November 20, 1995. AEPCO submitted its Phase II Acid Rain permit application on December 13, 1995. Through its letter of July 10, 1996, AEPCO requested changes to the responsible officials for the purposes of excess emissions reporting and truth, accuracy, and completeness of submittals. ADEQ had temporarily suspended the processing of Title V permits for electric utilities until early 1998. On April 13, 1998, ADEQ met with AEPCO to discuss outstanding issues. AEPCO sent additional information on April 16, 1998 including a request for burning petroleum coke in units 2 and 3. A separate application for permit revision was made by AEPCO on April 17, 1998, to allow petroleum coke combustion. However, this request for permit revision was subsequently withdrawn by AEPCO in a letter dated September 4, 1998. Since additional information requested and provided could not be summarized in a clear and concise manner in this document, only reference has been made to the those correspondences that requested and provided additional information.